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Preliminary containment evaluation in the Surat Basin, Queensland, Australia

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Abstract

The level of confidence in sub-surface containment related to potential industrial-scale injection of carbon dioxide (CO_2) is investigated in advance of applications for CO_2 exploration tenements. Evidence for seal retention pressures is evaluated based on hydrocarbon accumulations and hydrostatic gradients. Fracture propagation and fault reactivation pressures are also scoped. Evidence for vertical migration through a proposed seal is investigated through oil shows analysis. Analyses are synthesized and compared to required pressure retention performance, indicated by dynamic modeling, to give an overall view of pre-licensing, pre-drill containment confidence. The resultant uncertainty analysis is used to guide an exploration strategy.

Keywords: Containment, storage, Surat, Precipice, carbon dioxide, uncertainty, leakage

1. Introduction

The work presented here is extracted from a more in-depth case history of the ZeroGen Project [1] and highlights sub-surface containment factors only. The ZeroGen Integrated Gas Combined Cycle (IGCC) Project was an extensive project prefeasibility study which included the capture, transport and injection of 2-3 Mt/a (million tonnes per year) of CO_2 for nominally 30 years to securely store ca. 60-90 Mt (million tonnes) in an appropriate subsurface reservoir. As part of this, a decision was required on whether and where to invest in CO_2 exploration tenement applications. Confidence levels in sub-surface containment security in the nominal area of interest were investigated based on available data. The areas of interest cover the central Surat and underlying Southern Bowen basins in SE Queensland, Australia (Fig. 1).

For a given site and injection play (reservoir/seal pair) containment confidence is dependent on a given rate, pressure, duration and injected volume and depends on estimates of three key pressures (compared

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with required injection operating pressures). These relate to the caprock and are capillary entry pressures, fracture propagation and fault reactivation pressures.

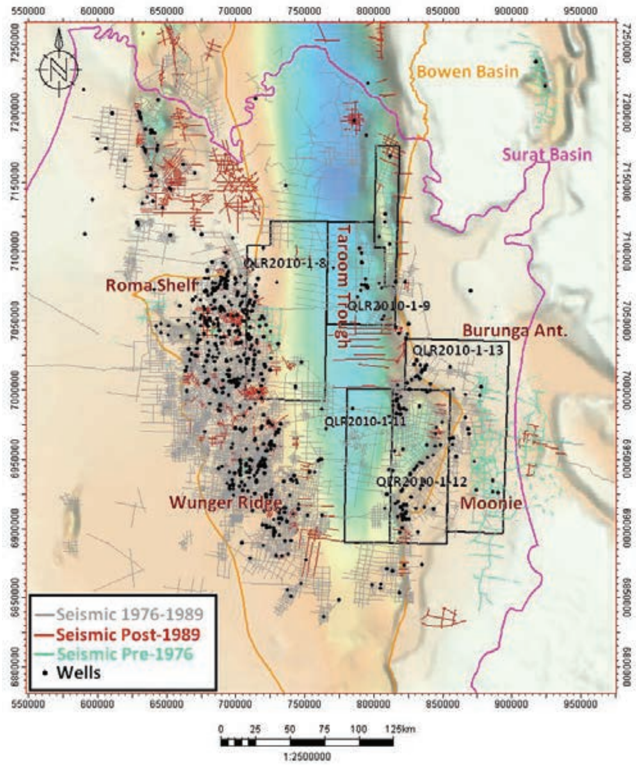

Fig 1. Area of interest in the Surat and Bowen basins, with all 2D seismic lines and wells. The tenements of interest are also shown. Basemap: Base of Phanerozoic from OZ SEEBASE™ [2].

The maximum pressure seen at the base of the seal should not exceed the lowest of these pressures (less some operating margin). Pre-drill, pre-tenement decisions should consider the degree to which seal quality is already "proven" through the presence of oil and gas accumulations in a play (if any). Basin geochemistry, oil shows and pressure gradients may also add insights.

Containment confidence needs also to address lateral migration through dynamic reservoir simulation studies which consider worst, credible cases of plume (and pressure) spread. In the context of Queensland greenhouse gas (CO_2) legislation, plumes must be contained within areas licensed for injection. *A priori* confidence is required that plumes can be so contained.

2. Top seal and intra-formational seals

The two main potential geosequestration plays are the Bowen Showgrounds Sandstone and Surat Precipice Sandstone plays (Fig. 2). The primary play (better reservoir quality and larger aerial extent) is the Precipice-Evergreen play. The upper Evergreen Formation is reported to be an extensive sequence of shale and siltstone with minor sandstone deposited in a lacustrine environment [4], [5], [6]. The Precipice-Evergreen sequences are complex [5] with localized lacustrine facies also along the base of the Evergreen Formation and/or upper part of Precipice Sandstone in the east. Such units could cause CO_2

migration paths to be tortuous, enhancing trapping mechanisms (solubility and residual saturation) and minimizing the amount of CO_2 reaching the base of the seal and the pressure seen by that seal [3].

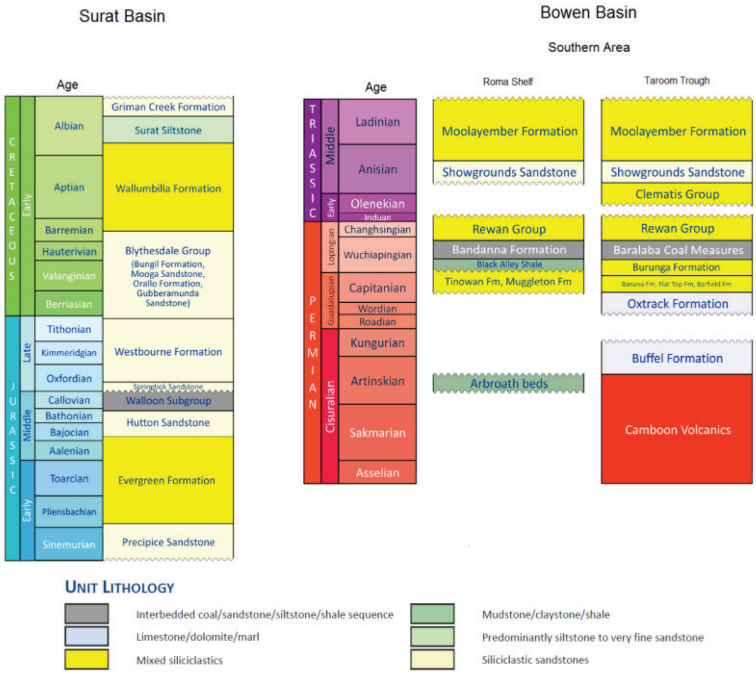

Fig. 2. Principal Stratigraphic Subdivision of the Sediments within the Bowen and Surat Basins (after [4]).

There are no available previous studies on the sealing capacity of the upper Evergreen Formation and no available MICP analyses. Historically, lithostratigraphic correlation has been the main correlation technique for these formations [5], with lithology determined largely through V-clay calculations. This determination generates a consistent (inferred to be "continuous") aerially consistent upper Evergreen Formation lithotype. The thickness of the upper Evergreen Formation increases from the flanks to the syncline center. It covers virtually all available CO_2 tenements with thicknesses greater than 40m, and depths greater than 800m. The seal is proven for hydrocarbon fields in Roma Shelf and Moonie area (Fig. 1) where it is relatively thin (ca. 40m). Sealing quality is expected to improve towards the syncline axis - the inferred lacustrine depocenter (Fig. 3). These central areas are thus the prime focus areas.

2.1. Hydrocarbon habitat (accumulations and shows)

The upper Evergreen Formation and locally the lower Evergreen Formation retain hydrocarbon columns to the west and east of areas of interest. Seals retention might be considered "proven" in these areas but only to pressures indicated by those columns. However, column heights have to be estimated from publicly available data (Table 1) and inform *minimum* retention pressures only.

Table 1. Column heights and reservoirs for five hydrocarbon fields in the Bowen and Surat basins. The immediately overlying seal is also listed. Only the Moonie Field is within one of the available tenements, QLR2010-1-12 (modified after [1]).

Hydrocarbon	Reservoir Unit	Estimated	Seal	Main Hydrocarbon	ΔP from estimated

Field		Hydrocarbon Column Height (m)		Type	column heights (bar)
Moonie	Precipice Sandstone	23	Evergreen Formation	Oil	2.0
Waratah	Showgrounds Sandstone	14	Snake Creek Member	Oil & Gas	1.2
Bony Creek	Precipice Sandstone	55	Evergreen Formation	Gas	7.5
Lamen	Precipice Sandstone	14	Evergreen Formation	Gas	1.2
Beaufort	Showgrounds Sandstone	17	Evergreen Formation	Gas	2.3

In the central area of the Mimosa syncline (Fig 3.), there are several exploration wells in which no shows were reported above the Evergreen formation. Most of the oil and gas shows reported in Hutton Sandstone are aligned with the fault systems on the margins of the syncline [5]. These could be associated with fault migration (Fig. 3), in particular for the fault systems located in the eastern margin of the Bowen Basin as described by Cadman *et al.* [7].

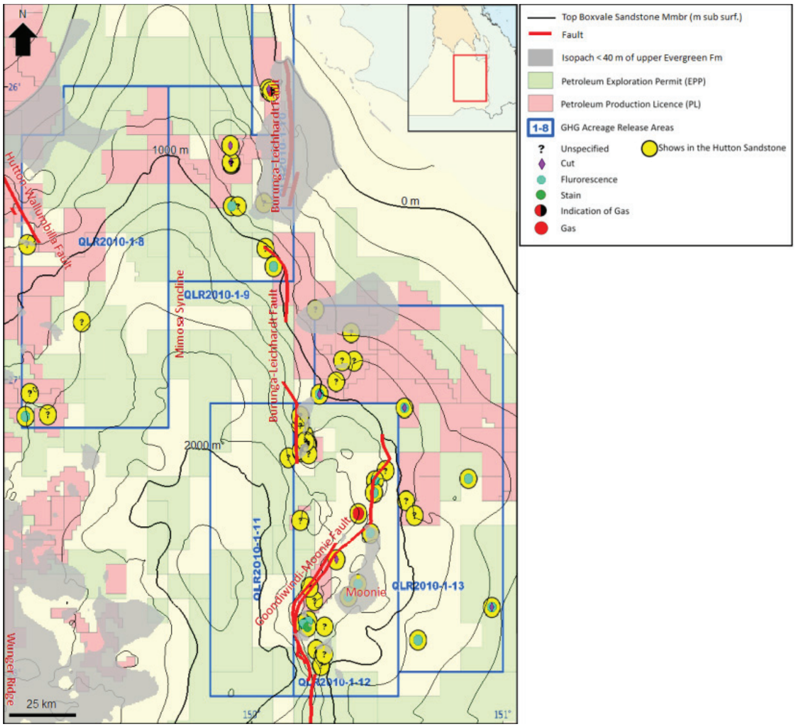

Fig. 3. Map illustrating presence of hydrocarbon shows recorded in the Hutton Sandstone in the CO_2 exploration tenements. Superimposed is the base of upper Evergreen Formation (black contour lines 200 m (mSS)). Grey areas denote upper Evergreen Formation thickness less than 40 m (source: CGSS, modified after [1]).

2.2. Hydrogeological aspects

Previous hydrodynamic studies [8], [9] have focused on the Precipice Sandstone and the Hutton Sandstone aquifers. Most of the data are located in the east and central regions of Surat (Fig. 3). Those studies provide some evidence for pressure separation through differences in hydraulic head in each aquifer *in some areas*. The estimated pressure difference (ΔP) between the Hutton and Precipice aquifers is estimated to ca.14 bar at the base of the Evergreen Formation in one case [1]. In addition to this, data from two clusters of wells in the south east part of Surat Basin (Figures 33 and 36A in [8]) also give some support for an Evergreen Formation seal, albeit only at smaller differential pressures.

3. Faults

The structural evolution of the area is discussed in [7] and [10]. In addition to known faults, there may be faults in the lower Jurassic, with sub-seismic resolution, which offset the upper Evergreen Formation. However, the presence of faults in many (if not most) hydrocarbon accumulations indicates that the simple *presence* of faults per se is not evidence for seal breach or vertical migration. Oil show data are consistent with fault-related, vertical hydrocarbon migration in some areas. Whether such migration has been episodic (e.g. through occasional, discrete, minor fault movements) or is continuous (e.g. through juxtaposition of non-sealing lithologies) is not determinable with current data.

Minimal geomechanical data are available for the Mesozoic strata in the Surat Basin region. Geomechanical properties and the present-day state of stress of the Permo-Triassic sediments of the Bowen Basin are better understood [11], [12]. The regional stress field of Queensland is consistently orientated north-northeast in the Bowen Basin [*ibid*]. Recent extended leak-off tests [1] indicate fracture gradient in the Northern Denison Trough (Northern Bowen Basin) of between 0.23 bar/m and 0.25 bar/m (1.0 and 1.1 psi/ft).

The main faults in the Bowen Basin strike north-northwest and are oblique to the maximum horizontal stress orientation. [11]. The fault architecture and mechanical properties of the existing faults in the sediments of the Surat Basin are not well understood. The majority of the faults (80%) in the uppermost kilometer of the crust are reverse. However, in the northern and southern Bowen Basin, 17% of the faults are strike-slip, and only 3% are normal faults [*ibid*].

Preliminary, fault stability analysis was carried out for three representative fault plane orientations. The first is the mean fault orientation in the Bowen Basin, [11], which represents the Hutton-Wallumbilla Fault. The other directions were the strike of the Goondiwindi-Moonie and the Burunga fault systems as described in [4] and also shown in Fig. 3. These are situated at the eastern side of the basin.

The vertical stress gradient was assumed to be 0.23 bar/m (1.0 psi/ft). Minimum and maximum horizontal stress magnitudes were estimated from Schlumberger owned data for the region. The stress regime at 1200 m depth was assumed as strike slip regime ($S_H>S_V>S_h$). Pore pressure was assumed to be hydrostatic (0.1 bar/m, 0.435 psi/ft). Rocks were considered to be unconsolidated (zero cohesion) in all cases.

Fault stability analyses were performed at varying friction angles in the range of 20 to 40 degrees [12]. In these simulations, pore pressure was increased until the reactivation threshold was attained.

Table 2 shows ΔP values- lower-bound estimates of overpressures required for fault reactivation. The fault direction which reactivates most readily on increasing pore pressure is the Moonie fault direction. In a worse case (though not sensu stricto a "*credible*" worse case, given the zero cohesion assumption) a pore pressure increase of 44 bar would lead to fault movement and risk of leakage.

4. Legacy and new well bores and lateral plume migration

There are legacy wells within the area of interest. Completion reports of these wells are available and the architecture and placement of barriers is recorded though reports are of variable quality. Cement bond logs are not available for some wells. Generally, legacy wells were not designed for CO_2 service. Plugged wells, depending on their vintage, have had varying degrees of casing removal and emplacement of cement plugs. No abandonment, test or completion reports have been found which indicate any isolation issues with legacy wells in the area. A simple risk reduction principle would be to site injection wells such that plumes would be unlikely to intersect legacy wells. Modeling indicated that this is feasible in the area of interest [1], [3] but confidence is dependent on quality reservoir models.

Table 2. Results of different model scenarios (variation in friction angle). During increase of the pore pressure critically stressed faults are predicted to reactivate after increasing pressure in the reservoir (Δ p) at 1200m depth, assuming zero cohesion (modified after [1]).

Friction angle assumption	ΔP		Fault directions critically stressed after increasing pore pressure (ΔP)
Degree	psi	Bar	
20	627	44	Moonie & Hutton-Wallumbilla
25	870	60	Moonie
30	1028	71	Moonie & Hutton-Wallumbilla
40	1270	88	Moonie & Burunga

5. Pressure evolution comparisons

Dynamic modeling of CO_2 injection is reported elsewhere [3]. For an open system, a sustained injection rate of 2 Mt/a resulted in a maximum overpressure modeled at the base of the seal of between 25 and 70 bar depending on modeled reservoir heterogeneity and permeability. Such estimates for open-formation scenarios are lower than those in which no-flow boundaries or compartments are present.

Modeled build-up pressures are thus higher than values for seal retention pressures estimated from hydrocarbon column heights (7.5 bar) and from hydrodynamic analysis (14 bar). For closed systems, this difference between “modeled build up retention requirements” and “values of retention supported by evidence” can be expected to be greater. There is currently inadequate support for the retention pressures required for industrial-scale injection rates.

With respect to fault reactivation potential, maximum overpressures, modeled at 6km from the injection well, were between 15 and 40 bar. Given worse-case estimates for fault reactivation and maximum modeled plume spread of the order of 6km [1], there is some preliminary confidence in a possible development scenario which does not risk fault reactivation.

6. Conclusions and implications for exploration programming.

James et al [13], discuss the application of Evidence Based Logic in storage site assessment using a numerical approach using Quintessa’s TESLA software. In this section, evidence for containment quality has been similarly examined, though only in an illustrative, qualitative sense.

Fig. 4 is an illustration of the relative support for containment confidence. The colour code provides an illustration of relative evidential support for adequate containment: red indicates the presence of data and evidence which does not support the required containment integrity. This is mostly at specific sites in the basins e.g. related to faults. Green illustrates for the presence of evidence and analyses which support the required containment integrity. White illustrates residual uncertainty.

The containment evaluation consists 4 sub-divisions i.e. caprock, faults & fractures, well-bores and lateral migration. The evaluation of each of these is a synthesis of lower level analyses (e.g. capillary entry pressures, hydrocarbon column heights and so on). Selected analyses are discussed below.

Overall, uncertainty (white) rather than risk (red) dominates. Where evidence is available which does not support containment, it is generally area specific and is related to fault-related vertical migration routes indicated by oil shows. By simply avoiding these areas (maintaining a large separation margin), those fault-related containment risk can be avoided. A similar argument could apply to legacy wells.

The difference between the containment pressures which are *required* to enable industrial scale injection and available evidence of containment pressures, supported by existing limited data, is large. Uncertainties in the required pressures are large due to uncertainties in reservoir connectivity and heterogeneity. These uncertainties also impact uncertainties in lateral migration distances and directions. Several techniques exist for reducing these uncertainties in an exploration program for example:

- Seal retention pressures can be measured in the laboratory. If seals are highly heterogeneous and residual uncertainties remain high after core and log analyses, then retention pressures can be further tested through vertical interference tests in the field.
- Likewise rock strength data can be obtained through core studies.
- Three-dimensional seismic data would assist in identifying and thus avoiding faults as well as characterizing reactivation and juxtaposition risk. It may also assist in delineating reservoir facies reducing uncertainty in pressure evolution.
- Extended well tests (production or injection) and lateral interference tests can provide critical information on flow barriers out to a required radius of investigation.

In contrast to oil and gas exploration, the declaration of a “discovery” for a storage site requires that containment (under operating conditions) to be established with a high level of confidence. That is, evidence is required which indicates that inherent containment pressures are greater than pressures which might evolve in an injection field and that injected CO_2 can be contained in licensed areas and away from key features. It is likely that initial data requirements for geosequestration sites are greater (and more expensive) and require significantly more in-situ dynamic pressure and flow tests.

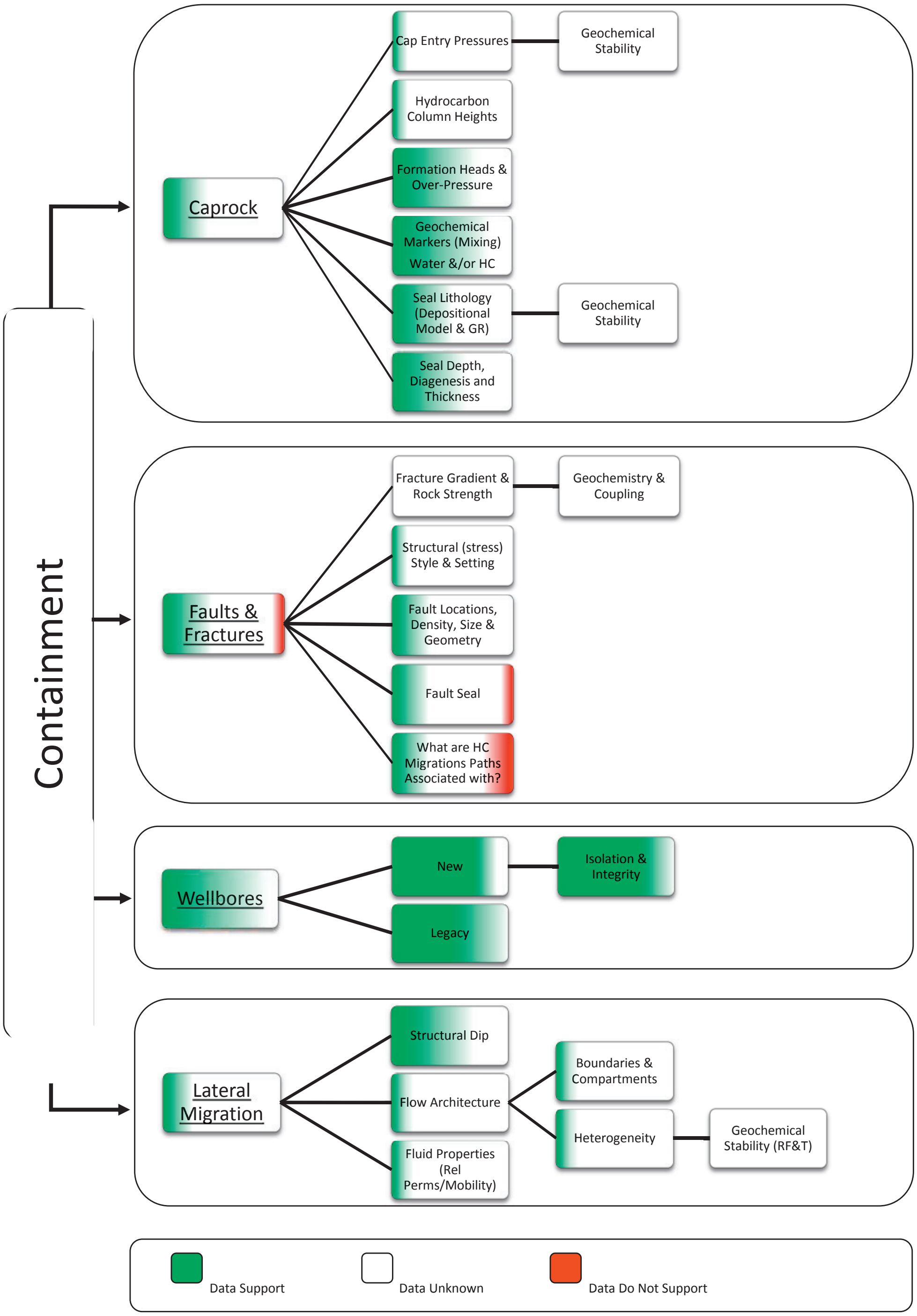

Fig 4. Illustration of overall containment confidence for caprock, faults and fractures, wells, and lateral migration. Red shading signifies where existing data does not support containment, green that integrity is supported by existing data. White denotes uncertainty.

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